Service Date: November 7, 1983

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER of the Commission's Investigation Into and Refinement of Electric Avoided Cost Based Rates for Public Utility Purchases From Qualifying Cogenerators and Small Power Producers	)	UTILITY DIVISION DOCKET NO. 83.1.2 ORDER NO. 5017

APPEARANCES

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BEFORE:

THOMAS J. SCHNEIDER, Chairman
JOHN B. DRISCOLL, Commissioner
HOWARD L. ELLIS, Commissioner
CLYDE JARVIS, Commissioner
DANNY OBERG, Commissioner

FINDINGS OF FACT

BACKGROUND, SUMMARY AND INTRODUCTION

1. In November of 1978, the President signed into law the Public Utility Regulatory Policies Act (PURPA). Section 210 of that Act required the Federal Energy Regulatory Commission (FERC) and state public service commissions to prescribe rules to encourage cogeneration and small power production (COG/SPP). Central to the requirements of Section 210 is the requirement that electric utilities purchase power from qualifying cogeneration and small power electric generating plants (qualifying facilities, QF's).

2. In 1981, the Montana Legislature passed and the Governor signed a bill that created a state "mini-PURPA" 69-3-601 et seq., MCA.

3. In May of 1981, the Montana Commission adopted rules that established general conditions under which utilities were required to purchase power to QF's. ARM 38.5.1901 through 38.5.1908.

4. An important feature of those rules is the requirement that utilities pay QF's rates that reflect the utilities' "avoided cost." Avoided cost is defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." Most of this proceeding has dealt with the details of computing this avoided cost.

5. PURPA included general requirements for QF rates because, according to the conference report, drafters "were concerned that the electric utility's obligations to purchase and sell under this provision might be circumvented by the charging of unjust and non-cost based rates for power solely to discourage cogeneration or small power production."

6. As part of its mandated implementation of both the federal and the state statutes, the Commission initiated Docket No. 81.2.15 in February of 1981. In this docket, the Commission established the method by which avoided cost rates were to be computed and reviewed contracts the utilities proposed to offer QF's. The Commission's decision in this docket was intended to assure QF's reasonable rates and contract conditions while at the same time protecting utilities and their retail customers from unreasonable risks and costs.

7. In general, the decision in Docket No. 81.2.15, while establishing a specific rate and general conditions for purchase of QF power, anticipated that many of the issues involved in such purchases would be resolved by utilities and QF's through good faith negotiation.

8. This proceeding was initiated in January, 1983, to review the avoided cost rates and methods previously adopted and to allow interested persons to present to the Commission their views on how those rates and methods might be changed and improved.

9. Prefiled testimony and four days of hearings resulted in a comprehensive record that presented the views of utilities, QF's and those who were interested in building generating plants that would qualify as QF's.

This record vividly revealed that there are major problems that plague the implementation of PURPA and Montana's "mini-PURPA. " These problems have acted as an almost complete barrier to Montana's utilities' purchasing QF power.

10. Perhaps the most significant problem has been potential QFs' uncertainty about rates they will receive in the future. The Commission's orders in Docket No. 81.2.15 contemplated that the avoided cost rates contained in each utility's tariffs would change yearly to reflect updated information of each utility's avoided costs. In addition to the tariffed rates, both the Commission's rules and its decision in Docket No. 81.2.15 contemplated that long-term fixed rates based on the method established by the Commission and negotiation, would be offered by the utilities.

11. Between the time of the decisions in Docket No. 81.2.15 and the hearings in this docket, the Montana Power Company (MPC) has failed to comply with the Commission's requirements for long-term contracts, including those that require fixed rates. Because of this failure, QF's have been offered only the tariffed rate which, they were told, would change yearly. Because QF's usually must have some assurance of rates they will receive in the future in order to obtain financing for their projects, MPC's failure to offer long-term contracts has kept QF development in Montana at a virtual standstill, since most of the interest in constructing QF plants is in MPC's service territory. MPC in this case has sought to correct this problem by offering contracts that feature both a fixed rate and annually adjusted rate. In this order the Commission seeks to rectify this problem by specifying the terms and conditions that must be contained in long-term contracts. Those long-term contracts will become a part of each utility's tariff.

12. Another area of uncertainty that has acted as a barrier to QF development is the concern by QF's that, should the Commission change the method by which avoided cost rates are computed, contracts that used former methods might be changed.

As is evident from this docket, computation of a utility's avoided cost can be performed in a variety of ways. Because of this diversity and because there were significant gaps in information then available, the Commission, in Docket No. 81.2.15 specifically contemplated refinement in both the method and the information used in avoided cost rate computations. Those future refinements, however, are not intended to abrogate existing contracts.

13. In this decision, the Commission explicitly finds that changes it might make in the future will not affect the terms and conditions of signed contracts. Changes that might be made will be prospective, that is, they will govern only those contracts signed after the changes are made.

14. Potential QF's also expressed concerns about several contract provisions which they claimed either introduced uncertainty or financially onerous obligations. This order addresses these concerns in such a way, the Commission believes, that these valid objections are addressed without compromise to the utilities' interests.

15. As with the prior docket, parties in this proceeding presented the Commission with a number of methods by which avoided costs may be computed. The Commission has chosen to

continue use of the method adopted in Docket No. 81.2.15, although with certain important refinements. This method requires utilities to use specific coal-fired generating plants and a hypothetical combustion turbine in their avoided cost computations. This method was found preferable for a variety of reasons, including verifiable accuracy of data. The Commission rejects claims that this method results in rates that are higher than the utilities' avoided costs. In fact, if anything, the method results in rates that may be somewhat less than actual avoided costs because it does not include avoidable transmission, distribution and reserve requirements costs. Because of lack of data, these elements could not be included in this decision.

16. The Commission has expended a great amount of time and effort on this order. It is, we believe, fair to all parties. The past two years have been difficult ones, it seems, especially for MPC in the implementation of what are clear mandates from both the federal government and the State of Montana. The time for hesitation and confusion must end. Cogeneration and small power production must be encouraged through the good faith implementation of this order.

17. Although this order at times refers to past orders in Docket No. 81.2.15, it is the Commission's intent that this order and the Commission's Rules governing QF purchases provide the sole basis for contract negotiations. References to past orders are intended only to serve as information for those interested in the history of the Commission's implementation of PURPA and Montana's "mini-PURPA".

AVOIDED COST RATES: THE BASE RATES

18. Summary of Issue. The basic issue in this proceeding is how much utilities should pay QFs for the power they produce. Under PURPA, electric utilities can be required to pay up to their avoided cost for QF power. Both the Commission and FERC have decided that utilities should pay their full avoided cost, which is the cost utilities would have to incur to provide additional electricity if the QF electricity were not available.

19. Montana Power Company. The MPC proposed two contracts that contained three avoided cost rate options (MPC Exh. 1, p. TAL-2 and RFC-2, 3). Each rate option, however, is similar, since each consists of energy (kwh) and capacity (kw) elements. The energy element consists

of avoidable variable operation and maintenance (O&M) costs, fuel inventory and working capital costs; these elements, when combined, are referred to as short-run variable operating costs, running costs, or system lambdas. These costs are grouped together because they change according to how much total electricity is produced by a utility. The capacity element is computed as the reduced revenue requirement due to a deferral of the Company's prospective resource additions.

20. The resulting base rates proposed by MPC for the energy and capacity elements, and the combined rate, are summarized in Table 1 below.

TABLE 1

The Montana Power Company' s
Proposed Avoided Cost Rates[1]

Year	Energy (¢/kwh)	Capacity ($/kw/yr)	Combined[2] ¢/kwh
1983	2.121	60.30	3.10
1984	1.241	64.52	2.29
1985	1.172	69.04	2.30
1986	1.553	73.87	2.76
1987	1.277	78.30	2.55
1988	1.726	83.00	3.08
1989	1.537	87.98	2.97
1990	1.645	93.26	3.17
1991	4.307	98.85	5.92
1992	3.411	104.79	5.11

1 Source: MPC Exh. 1, Exh. TAL-7, as amended by the Commission hearing Data Request No. 3, Page 9 of 9 July 7, 1983

2 Computed as ($/kw/yr)/(8760 · 0.70) plus the energy payment.

21. The rates in Table 1 are in current year's dollars, which include inflation as opposed to constant dollars which do not. These rates do not change for QF's of different sizes, and do not change to reflect rates for long-term QF contracts as opposed to short-term contracts.

22. Pacific Power & Light. PP&L has indicated that its standard approach is superior to other approaches (PP&L Exh. 1, p. 4). PP&L's standard rate offering varies, depending on whether the QF contracts for a fixed amount of capacity or whether it only contracts to deliver capacity when it happens to be available. (In technical terms, this is a firm/nonfirm distinction.) The basis of the firm/nonfirm distinction, however, is not stated. The short- versus long-run distinction apparently hinges on the most recent estimated on-line data for the Wyodak 2 plant. PP&L's proposed rates also vary, depending on whether a QF signs a long-term or a short-term contract (PP&L Data Response No. 2, Appendix A).

23. The following table extracts from a Company data response its proposed avoided cost rates.

TABLE 2

Pacific Power and Light's
Standard Avoided Cost Rates[1]

		Firm Power		
Year	Nonfirm Energy (Ave. ¢/kwh)	Energy Ave. ¢/kwh	Capacity ($/kw/yr)	Combined[2] ¢/kwh
1983	1.6	1.59	29.16	2.07
1984	1.7	1.75	32.04	2.27
1985	1.9	1.77	32.40	2.30
1986	2.0	1.85	33.84	2.40
1987	2.1	1.94	35.52	2.52
1988	2.2	2.06	37.68	2.67
1989		2.18	39.96	2.83
1990		2.31	42.36	3.00

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1 Source: PP&L Data Response No. 2, Appendix A.

2 Computed as ($/kw/yr)/(8760 · 0.70) plus the energy payment.

1991	6.88	90.84	9.05

24. Like MPC's proposal, these rates are in current year's dollars. Also, it is worth noting the impact on the avoided cost rates of a short-run/long-run time distinction: the rate triples between 1990 and 1991.

25. Montana-Dakota Utilities. MDU's proposed rates include recommendations that set a standard rate for QF's of 100 kw or less and distinguish between firm and nonfirm QF power (MDU Exh. 1, p. 5). To support its recommendation, MDU claims that the avoided cost of one QF producing 1500 kw is less than if MDU buys power from 1500 QF's who produce one kw each. (Ibid., especially pages 5 and 6). MDU further argues that nonfirm power only allows for avoidance of "running costs" (Ibid., p. 9), that is, costs that vary according to how much power the utility generates. In its direct testimony, and in its Opening Brief, MDU argues that there is no basis to assume the existence of a portfolio effect in its jurisdiction since it does not believe that a large number of QF's will be built in its service territory. A portfolio effect approach assumes that, although one QF may not provide firm power, a number of QF's in the aggregate will provide firm power for the utility. On this basis, MDU argues that a firm/nonfirm rate distinction is necessary, and the capacity payment should be eliminated from the short-term contract.

26. Ultrasystems. Ultrasystems, Inc. (UI), presented testimony advocating that an avoided cost based rate be incorporated in standard tariffs. These rates would be available to all QF's. (UI Exh. No. 2). UI also suggested that the Commission tariff a long-term avoided cost rate that fixes the pricing methodology over the life of a signed contract (UI Exh. No. 2, p. 5, and TR. p. 623).

27. The Commission's Existing Avoided Cost Rates. In Docket No. 81.2.15 the Commission tariffed short-term and long-term avoided cost rates (see especially, pages 14, 15 and Appendices of Order No. 4865). The existing short-term rate is similar to MPC's proposed rates in this docket; the Commission's short-term rate, however, includes a system lambda calculation and a nominal aggregate capacity credit not contained in MPC's proposal.

28. The Commission's current long-term rate separates energy and capacity elements and is based on the capital and operating costs of a coal-fired generating plant and a combustion turbine.

29. Commission's Decision. The Commission finds that the methodology developed in Docket No. 81.2.15 is valid and should continue to be used (although with some modification) to compute full avoided cost rates.

30. The short-run/long-run rate distinction contained in the current tariffs should continue. The Commission rejects use of distinctions based on QF size or firmness of power. MDU's arguments in favor of such distinctions, which goes only to a short-term rate, are flawed. In any case, if a

utility acquires QF power, this power should be included along with the utility's other resources when making the subsequent year's system lambda calculations. Then, at most, the current year's system lambda calculation would err on the high side, other things being equal, for a period of one year -- assuming a utility acquires QF power on July 1 of a contract year. For purposes of computing system lambda, however, the utilities may use a one mw decrement. This level exceeds the QF capacity additions to the MPC system in the recent past (TR, p. 135).

31. MDU's connection between the value of firm power and the size of the decrement, for system lambda calculations is flawed. The Commission agrees with MDU's claim that the total cost of 15,000 generating plants producing one kw each is more than the total cost of a single generating plant producing 15 mw. However, MDU's argument that there will be no QF portfolio effect in its jurisdiction, is unsubstantiated. QF generation is in its infancy, and the fact that MDU does not have QF power today does not prove that it won't tomorrow. MDU's Montana service territory is large. Wind generation is, of course, a real possibility. In addition, UI suggested that they are examining locations in MDU territory for cogeneration facilities. In fact, MDU's brief states that: "Montana is a large state with diverse and varied characteristics and conditions." (Opening Brief, p. 3) Regarding MDU's allegation of "...the lack or diversity of type..." (Opening Brief, p. 8), MDU has not shown that the only QF potential is in wind. The record, in fact, contradicts this statement (TR, pp. 125-126, 609-610). The Commission's approach is consistent with FERC regulations, which require the consideration of "The individual and aggregate value of energy and capacity from qualifying facilities . . ." (emphasis added). 18 CFR, 292.304(e)(2)(vi).

32. In computing the energy and capacity components of the Commission's long-term rate (hereafter referred to as the Base Long-Term Rate), the utilities shall use the following resources. MDU shall use Antelope Valley Station No. 2 (AVS 2) and a generic combustion turbine (CT), respectively, for the baseload and peakload facility (see MDU Data Response Nos. 9 and 11). The MPC and PP&L shall use Colstrip 3 and 4 and a generic CT as the basis for baseload and peakload cost estimates respectively.

33. For the following reasons the Commission finds that the above resources should be used as a proxy of each company's resource plan for purposes of developing avoided cost rates.

34. First, each company's resource plan is constantly changing. Therefore, if those plans were used to compute the avoided cost rates, those rates would be very volatile. In Docket No. 81.2.15, for example, each utility included a combustion turbine as a peaking resource. MPC's current resource plan excludes a combustion turbine. MPC's and PP&L's resource plans have changed radically. PP&L no longer includes Washington Public Power Supply System Unit Number 3. MPC recently decided not to include the Hanford extension resource in its plans: in April, 1983, it is in; in June it is out. In addition, the MPC recently changed the name of "Resource '89" and slipped the date of commercial operation from 1989 to 1996. Furthermore, both MPC and PP&L have expressed interest in marketing large amounts of capacity. There is, however, a common denominator to each utility's resource plan: On the horizon each includes a baseload coal-fired generating facility.

35. Second, the Commission has, in relative terms, more accurate cost data for say Colstrip 3 and 4 than for future resources e.g., Salem and Wyodak 2. That is, the construction cost estimates for Colstrip 3 and 4 are by and large already incurred and known. On the other hand, the costs of future resources e.g., Salem are by and large necessarily speculative, as are the cost indices. Moreover, MPC's Salem Project is not officially permitted by the Montana Board of Natural Resources. While Wyodak 2 and the Salem Project are the marginal resources in the long run, their respective on line dates are moving targets and, consequently, so are their respective cost estimates. In any case, for at least MPC, the cost of Colstrip 3 and 4, when put on an equivalent economic cost basis, is conservatively less than the cost of the Salem project. The cost of Colstrip 3 and 4 equals

$1668/kw (Revised Data Response No. 11, Attachment C, dated June 17, 1983), and Salem costs $1859/kw (Revised Data Response No. 32B, dated June 17, 1983). For these and the following reasons, the Commission finds that the resources discussed in Finding No. 32 above are the best proxies for purposes of avoided cost rates.

36. In sharp disagreement with the MPC, the Commission finds that the best cost estimate, which is, in fact, a conservative estimate, of an avoidable baseload coal-fired electric generating plant is Colstrip 3 and 4. As stated in a MPC data response (Data Response No. 10), the Company's resource plan includes existing and, as yet, nonoperating plants; furthermore, the MPC's resource plan is claimed to be based on a least-cost expansion analysis (see MPC Exh. 1, p. TAL-5 and TR, p. 216). Consequently, absent evidence to the contrary, one must assume that the MPC constructed Colstrip 3 and 4 on the basis of relative costs: these plants were cheaper than any other resources that could have provided power at the time the MPC opted to construct Colstrip 3 and 4 according to testimony provided in this Docket. Rather than rely totally on forecasts of inflation, fuel costs and costs of money to develop the elements of the avoided cost equations, the Commission finds that current economic costs are most accurate; this decision largely avoids the forecasting risks alleged by the MPC and PP&L (MPC Opening Brief, p. 16, and PP&L Reply Brief, p. 5). In the case of MPC and PP&L, the use of current Colstrip 3 and 4 cost estimates will minimize risks of overpayments. MDU shall use the AVS 2 facility as the proxy for avoidable baseload generating plant costs. The selection of this facility is based on the fact that the AVS 2 is the next baseload facility in MDU's resource plan. Consequently, the costs are known with greater certainty than for the AVS 3 addition.

37. The Commission finds that the resulting generation based avoided cost rates will minimize the error of over- or underpayments to QF's. As discussed in this order, nongeneration costs such as transmission and distribution costs are not included in the avoided cost rate; therefore, to the degree that the rate may not reflect full avoided costs, it is conservative. In comparison, the Commission finds that the avoided cost rates proposed by the MPC and PP&L underestimate the true full avoided cost rate (see Finding Nos. 20 and 23 above). As stated in testimony, the MPC's estimate of the levelized cost per kwh for Colstrip 3 and 4, plus operating costs, falls in the 58 mill/kwh range

(TR, pp. 187, 447); as PP&L also owns a share of Colstrip 3 and 4, its Colstrip 3 and 4 costs must be of a similar magnitude. Yet, if one contrasts the 58 mill/kwh (which excludes a capacity payment) cost estimate with either the MPC's or PP&L's proposed avoided cost rates there appears a substantial disparity. Not until year 1991 does the avoided cost rate offered by the MPC (for energy and capacity) exceed the 58 mill level. In addition, the MPC's combined ¢/kwh payment in year 1991 includes the highest energy payment the MPC would pay between year 1983 and year 2003 (see MPC's response to the Commission hearing Data Request No. 3, p. 9 of 9, July 7, 1983).

38. It is also useful to contrast PP&L's retail rates with its proposed avoided cost rates. The following table summarizes some of PP&L's current retail rates [The three customer classes in this table accounted for 99.45 percent of PP&L's total kwh sales in the State of Montana in year 1982 (Source: Table 16-15 of Exh. No. 16 in Docket No. 83.5.36)]:

TABLE 3
PP&L Retail Rates[1 3]

	Energy (¢/kwh)	Capacity ($/kw/Mo.)
Schedule 7 Residential	3.248 - 6.691	Included in Energy
Schedule 22[2] General Service	4.053	1.61 - 2.41 (For kw demand in excess of 15/month)
Schedule 48T		

1 Source: Pacific Power and Light Montana jurisdictional tariffs. Effective August 3, 1983, Docket No. 83.5.36, Order No. 5009.

2 These rates are for energy and demand metered General Service Customers (Load Level II). Load Level I includes only energy rates with a range of 4.443¢ - 4.039¢/kwh.

3 Note also that retail rates include cost components that would be excluded from avoided cost rate calculations e.g., billing and customer costs.

Large General Service	3.202	2.07 - 1.39 (For each kw of demand)

As with MPC, not until year 1991 does PP&L offer an avoided cost rate that exceeds any of its 1983 retail rates.

39. In its brief, PP&L compares the existing PP&L retail rates to the Commission's tariffed PP&L avoided cost rates concluding that, because the avoided cost rate exceeds the retail rate there is telling evidence that the avoided cost rate is flawed (PP&L Opening Brief, p. 4, Footnote 2). A moment's reflection will show, however, that this is an apples and oranges comparison. Retail rates are limited by a revenue requirement, which is based on the utility's old inexpensive investments as well as its new expensive investments. By contrast, by definition, an avoided cost calculation is based only on a utility's new investment.

40. From a common sense point of view, the utilities' proposals must be viewed with great suspicion, since they reflect rates dramatically lower than what utilities are asking for in their own rates as new utility-owned plants begin to generate power. MPC will not seek rates reflecting costs of 2.30¢/kwh for Colstrip 3 and 4, having testified in this docket that Colstrip power will cost approximately 5.8¢/kwh.

41. ln summary, the Commission finds its existing avoided cost methodology, with the changes made in this order, appropriately reflects full avoided costs.

Long-Term Rates

42. Summary of Issue. The fundamental issues here relate to whether it is appropriate to establish by tariff, a long-term avoided cost rate that is fixed for the life of a contract. The alternative is a rate that would change yearly. If a fixed long-term rate is to be used, the following issues must also be resolved: 1) whether utilities should be required to offer rates that are higher than avoided costs in the early years of a contract and lower than avoided cost in the later years of a contract. In technical terms this is called a levelized rate; 2) what elements of the Commission's Base Long-Term

Rate[1] should be levelized; 3) whether levelization should be on a beginning-, or end-of period basis; 4) what type of carrying charge should be used -- real or nominal; and 5) what escalation and discount rates should apply.

43. Montana Power Company. While proposing one type of a long-term levelized rate, the MPC expressed concern over the risk of levelization. In its direct testimony the MPC proposed to offer a contract featuring levelized capacity payments with annually adjusted energy payments (See MPC Exh. 1, p. TAL-4 and Exh. No. TAL-7). In its levelization, the MPC argues that a beginning-of-period perspective, rather than end-of-period is correct as "...QF's would receive payment for capacity immediately upon commencing production." (See MPC's response to the Commission's hearing Data Request No. 9, p. 1 of 3, July 7, 1983). Although the MPC is willing to offer a partially-levelized avoided cost rate, it expressed a preference to offer a "...rate based on payments escalating with inflation" (See the MPC Opening Brief, p. 16).

44. The MPC's expected escalation rates for the components contained in the Commission's Base Long-term avoided cost rate were provided in data responses (See MPC Data Response No. 39). The MPC also provided a Colstrip 3 and 4 weighted cost of capital estimate. (See Data Response 11, Attachment A).

45. Pacific Power and Light. PP&L testified that QF's which defer or displace any portion of the Company's avoidable plant should receive long-term avoided cost rates (PP&L Exh. 1, p. 4). PP&L notes, however, that avoided cost rate levelization "...does create risks to utility ratepayers..." (PP&L Reply Brief, p. 5); and that "...it is not correct to levelize the variable energy component for the length of a QF/Pacific contract." (PP&L Data Response No. 5). PP&L's own standard avoided

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1 Note that the Commission's resulting long-term rate from Docket No. 81.2.15 is not actually a rate that features any permanence, but rather a method that is constant. The Commission's present development of a Base Long-Term Rate is defined below (Finding No. 69 and Table 4).

cost rate offering after year 1990, however, features constant -- presumably levelized -- energy and capacity payments (PP&L Data Response No. 2, Appendix A, p. 2 of 2). PP&L suggests that a long-term rate featuring an escalating stream of payments may be less risky to ratepayers and more desirable to QF's (PP&L Data Response No. 5). PP&L has also provided escalation rates for the variable components of the Commission's Base Long-term avoided cost rate (See PP&L Hearing Data Response No. 2, July 13, 1983).

46. Montana-Dakota Utilities. MDU has not, in this docket, expressed concern over long-term avoided cost rates. For purposes of levelization, MDU has provided growth rates for the variables in the Commission's Base Long-term avoided cost rate (See MDU Late Filed Exh. No. 2, July 8, 1983).

47. Ultrasystems, Inc. In its direct testimony UI states that it is desirable to have the Commission "...precalculate a variety of 'long-term avoided cost' payment options..." (UI Exh. 2, p. 7); UI goes on to request the Commission to establish values for the components for a long-run avoided cost calculation. For purposes of levelizing a component, UI provided an illustrative example adopted from the Electric Power Research Institute's Technical Assessment Guide (See UI Exh. 2, Appendices 1 and 2). UI also argues for a long-term rate option that is not fully levelized (TR, pp. 623-630, and UI Brief, p. 34).

48. The Commission's Existing Long-Term Rate Policy. In Docket No. 81.2.15; the Commission set forth policies that left to QF/utility negotiations the development of nonstandard long-term payment options. In that Docket, the Commission described various approaches to long-term rates that it found acceptable.

49. Commission's Decision. Based on testimony in this docket (see TR. pp. 259, 637), and concerns expressed to this Commission by prospective QF's, the Commission finds that three long-run avoided cost rate options should be fixed by tariff. The three options include a completely levelized rate option, an escalating (partially levelized) rate option, and the option to have unlevelized rates. The basis for these options shall be the current year's Base Long-Term Rate. The following provides the mechanics to compute these rate options.

50. A Base Long-Term Rate shall be computed by each utility. The method used to compute the Base Long-Term Rate shall be, with the below amendments, the method set forth in Order No. 4865, Appendices A & B[1]. The time reference for the initial year's dollar estimates shall be January 1, 1984. Each subsequent year's dollar estimates shall be revised to reflect the previous year's inflation. For example, the January 1, 1985 capital cost estimates shall incorporate the January 1, 1984 dollar estimate plus a factor -- multiple -- equal to one plus the actual capital cost inflation rate. The source of the actual inflation rates shall, in turn, be the Handy Whitman indices for the Plateau Region. The other cost elements (fixed and variable O&M and coal cost) shall be inflated to each subsequent year based on the previous year's actual inflation rates.

51. The Commission finds, for purposes of a base rate, that the fixed charge rates should be in real terms. Order No. 4865 was not specific in this regard. Pursuant to Order No. 4854, however, the utilities filed workpapers, each of which incorporated nominal carrying charges. The Commission, Ultrasystems, and PP&L agree that the use of a nominal carrying charge rate effectively levelizes the capacity payment for the economic life of the plant.[1]

1

The long-term rate tariffed in Order No. 4865 featured the following elements:

i) Energy Payment
- X ¢/KWH for all KWH purchased, where X equals the annualized unit cost of owning and operating a baseload plant, less the annualized unit cost of owning a combustion turbine, plus fuel costs (coal) and variable O&M for a baseload facility, and

ii) Capacity Payment
- Y $/KW(cf) for all contracted KW, where Y equals the annualized unit cost of a combustion turbine and CF represents the negotiated expected or demonstrated QF plant capacity factor.

1

Economically it is incorrect to combine <u>real</u> capital costs with a <u>nominal</u> carrying charge. Ultrasystem’s Exhibit No. 2 (Appendix 2, p. 2-1) features a capital cost component of an illustrative avoided cost rate equal to 5.22¢/kwh. This amount is invariant with respect to contract length -- one year or thirty years -- and stems from the fact that a nominal carrying charge was used to levelize the capital costs. Also, as pointed out by PP&L, an "anomalous situation" results from mixing <u>real</u> capital

52. A levelized long-term avoided cost rate shall be an option available to any QF willing to sign at least a four-year contract. This minimum term is based on evidence in Docket No. 81.2.15 that it takes utilities approximately four years to construct new combustion turbine plants. This evidence was not rebutted in this proceeding. An end-of-period time perspective, as described in Ultrasystem's testimony (Ultrasystems Exh. 2, Appendix 1), shall be used when levelizing rates. The Commission finds the MPC's suggestion, that a beginning-of-period time perspective better matches the payments to QF's, to be unfounded: QF's are paid for actual production after the fact (see MPC Exh. 1, RFC-1, Section 4.2).

53. Table 4 provides an illustration of levelized avoided cost rates for four different contract lengths using the method required by this order and illustrative data. The utilities are directed to use escalation rates (nominal) submitted in data responses in this docket for each element in the long-term levelized rate option. Discount rates (nominal) should reflect each Company's overall-incremental weighted cost of capital. To the extent expected escalation rates vary, so should the resulting avoided cost rates

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costs with nominal carrying charges (Opening Brief, p. 5).

TABLE 4

Long-Term Levelized Rates for PP&L[1]

	Base Long-Term[2] Rate Variable	Base Long-Term[3] Rate Input Data	Illustrative[3] Levelized Values 4 yr.	10 yr.	20 yr.	35 yr.
a.	$/kw (Baseload):	1686	2029	2456	3150	4009
b.	$/kw (Peakload):	360	433	525	673	856
c.	Fixed Charge Rate (Baseload) %:	8.1	8.1	8.1	8.1	8.1
d.	Fixed Charge Rate (Peakload) %:	10.0	10.0	10.0	10.0	10.0
e.	Fixed O&M Baseload $/kw:	15.26	18.0	22.0	29.0	36.0

1 The data used is for illustrative purposes but approximates PP&L's actual. The rates also include the below discussed line loss adjustments (Finding No. 69).

2 See Appendix B of Order No. 4865 for the methodology.

3 Levelized assuming an overall constant 8% escalation rate, a 12% nominal discount rate, and the levelization procedure discussed in Ultrasystem's Exhibit No. 2.

f.	Fixed O&M Peakload $/kw:	6.37	8.0	9.0	12.0	15.0
g.	Line Loss %:	8.3	8.3	8.3	8.3	8.3
h.	Coal Cost $/Ton:	12.16	15.0	18.0	23.0	29.0
i.	Btu/LB	8500	8500	8500	8500	8500
j.	Btu/kwh	10819	10819	10819	10819	10819
k.	Variable O&M Baseload ¢/kwh	0.24	0.29	0.35	0.45	0.57
	Rates:					
	Energy: ¢/kwh		3.66	4.44	5.69	7.21
	Capacity: $/kw[4]		0.59	0.70	0.91	1.15
	Combined ¢/kwh		4.25	5.14	6.59	8.36

4 The capacity payment is converted to an energy payment assuming an 85% capacity factor relative to the 85% availability factor.

54. As an alternative long-term rate, each utility shall offer a long-term escalating rate option. Unlike the levelized option, the escalating option shall be based on actual escalation rates (nominal) for the past year rather than forecasted escalation rates. A QF shall also have the option of a partially levelized rate e.g., one where the capital cost element is levelized and the variable costs are escalated. If a QF opts for the fully escalating rate option, the actual rates will simply equal the Base Long-Term Rates as updated each year. As with the fully levelized option, the escalating option also requires a minimum four-year contract.

55. In June of 1984 (and in June of each subsequent year), each utility must file with the Commission actual year 1983 nominal escalation rates for updating the 1983/1984 Base Long-Term Rate data inputs. The utilities must each develop and file with this Commission levelized long-term avoided cost rates for the energy and capacity components for a 4, 10, 15, 20, 25, 30 and 35 year contract.

56. In summary, the Commission finds the above menu of long-term rate options to reflect the generation-related full avoided costs. (TR, p. 17)

Time Differentiated Rates

57. Summary of Issue. The issue here is whether QF rates should vary according to a utility's cost as they vary by season or by time of day.

58. The Utilities. In this docket the utilities have not proposed time-differentiated rates, although evidence exists that costs vary by time of use (TR. pp. 128, 129, 486).

59. Commission's Decision. The Commission left to each utility the voluntary development of time differentiated rates in Docket No. 81.2.15 (See Order No. 4865, Finding Nos. 27, 29 and 32). An absence of testimony in the instant proceeding on time differentiated rates suggests to the Commission that they are not needed at the present time. The utilities are encouraged to develop and submit to the Commission time-varying rates if they so choose.

Line Losses

60. Summary of Issue. A certain amount of electricity is lost as it is transported through transmission lines from the generating plant to the customer. This fact is relevant in establishing avoided cost rates, since it is a cost that might be avoided by the utilities if QF's generate power. Each utility has presented testimony on the line losses it incurs that conflicts with the Commission's line loss estimate included in existing avoided cost rates.

61. Montana Power Company. MPC performed load flow and loss studies using standard computer programs referred to as the Power System Simulator/Engineering (PSS/E) package (See MPC Data Response No. 19). With the PSS/E programs the MPC computed a simple average avoided energy line loss of 3.4 percent (see Exhibit MPC 1, pp. DBG 21-26 and TR, p. 137). MPC proposes to apply this simple average line loss to the energy component of the avoided cost rate (Ibid., p. DBG-25). MPC has also indicated that a small QF's contribution to the MPC's transmission system line losses are too small to accurately model, and that QF's may actually increase transmission line losses.

62. Montana-Dakota Utilities. MDU states that it is highly speculative "...to attempt to develop a uniform formula for factoring line losses into standard avoided cost rate" (Exh. MDU 1, p. 12). MDU further alleges the line losses with QF's of 100 kw or less are inconsequential, and that losses are site specific.

63. Pacific Power and Light. PP&L states that line losses are not avoidable in serving the Company's Montana service territory (PP&L Exh. 1 p. 8). PP&L's inability to avoid line losses stems from the fact that all power required to serve its Montana loads is wheeled by BPA to Montana. The resource purchase contracts with BPA include the wheeling component as a fixed component of the power cost (See PP&L Data Response Nos. 11 and 27).

64. Ultrasystems, Inc. UI has testified that the Commission's current approach used to quantify line losses is reasonable but that the method can be refined. UI's proposed refinements include adjusting losses by voltage level and quantifying losses on a regional basis. Although UI has testified that line losses vary by season, by time of day, and "through time," it argues for

grandfathering line losses at the time a contract is signed by a QF and a utility (UI Exh. No. 2, pp. 11-12).

65. Commission's Existing Line Loss Policy. In Docket No. 81.2.15 the Commission established a "nominal energy loss factor" of 8.3 percent; this factor, in turn, reflects an average "...of transmission level energy losses as calculated by Mr. Ambrose for the MPC system" (See Order No. 4865, Finding No. 20). The 8.3 percent line loss factor was used in both the Commission's short-term and long-term energy rate calculations for each utility.

66. Commission's Decision. Line loss calculations are extremely complex, as is indicated by the variety of positions presented. There is agreement, however, that losses vary with the site of the generating plant and voltage level of the energy transmitted.

67. In spite of the complexities involved in quantifying line losses the utilities in the regular course of their business have negotiated contracts with other utilities or federal power agencies that include simple line loss estimates. MDU states that its agreement with the Western Area Power Administration (WAPA) features a 7 percent line loss rate, "regardless of distance from point of input" (See MDU Data Response No. 6). PP&L has negotiated transmission line loss estimates that are generally in the 7 percent range; also, it is apparent from these contracts that line loss percentages do not change because of voltage level and time-of-use (See PP&L Data Response Nos. 25 and 26). PP&L further indicates that its BPA wheeling contract was signed five or six years ago, which suggests that the magnitude of line loss changes over time does not warrant negotiation of a new contract (TR. p. 113). MPC's line loss contract with WAPA, varies with the transmission distance, but has not changed since the early 1960's -- i.e., "through time." (See MPC Data Response No. 27). The Commission takes official notice that, in Docket No. 82.8.54, MPC indicated that marginal transmission energy losses equal 8.71 percent and 7.57 percent respectively for the winter and summer periods (See Docket No. 82.8.54, MPC Data Response No. 1 to the Montana PSC's third set of data requests).

68. Balancing this conflicting testimony, the Commission finds that the existing generic line loss factor of 8.3 percent is reasonable. This percentage, although specific to MPC, is not significantly different from line losses included in contracts negotiated by PP&L and MDU.

Although PP&L's current contract with BPA includes wheeling costs that include line losses as a fixed component, it is evident from other line loss contracts negotiated by PP&L that substantial line losses exist. Past contracts that assume no QF power from Montana cannot determine appropriate line losses which must necessarily assume QF power in Montana. PP&L should renegotiate its BPA contract as QF power is acquired on its Montana system[1] (See TR. p. 113). The Commission does not agree with MPC's and MDU's allegation that avoided line losses with small QF's are inconsequential. Although the physical avoided line loss (actual number of kwh and kw) savings with small QF's may be small, the fact remains that utilities incur line losses that are avoidable.

69. The Commission finds it necessary to amend the application of the line loss percent to the long-term energy rate. Presently, the 8.3 percent line loss is only applied to the first term of the long-term energy equation[2]. The logic underlying this application is that this term is truly energy related: utilities incur the cost of baseload capacity costs, in excess of combustion turbine capacity costs, because of the fuel savings (energy) that result. As such, a portion of baseload capacity costs are incurred to provide energy (kwh). The Commission finds that, not only plant costs, but also

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1

The Commission would note that the BPA's recent publication "An Analysis of BPA Conservation Program Levels for Fiscal Years 1984 and 1985 and Their Relationship to a Least-Cost Resource Mix" assumes a 7.5 percent transmission line loss. Bonneville Power Administration, Office of Conservation, May, 1983.

2

This is the first of the three terms in the long-term energy rate set forth below in this finding. Also, see Order No. 4865, Appendix B.

baseload fuel and variable O&M costs (the second and third terms of the Commission's long-term energy equation) vary with the level of line loss. Consequently, the 8.3 percent line loss must be multiplied times all three terms as follows: Long-term energy =

$$\frac{(a\,c+e) - (b\,d+f)}{8760\,(.70)} \quad + \quad \frac{hj}{i} \quad + \quad k \quad 1.083$$

Avoided Transmission, Distribution, and Reserve Requirements Costs

70. Summary of Issue. The Commission's principle concern is whether QF's allow utilities to avoid incremental transmission and distribution costs related to the utilities' generation facilities -- Colstrip 3 and 4 and Antelope Valley System No. 2 and whether QF's allow utilities to reduce reserve requirements.

71. The Utilities. MDU states that transmission costs are avoidable only "...if the entire generating station being connected was deferred by the qualifying facilities interconnected to that utility's system" (See MDU Data Response No. 4). While PP&L did not testify as to the appropriateness of including avoidable transmission costs in an avoided cost calculation, PP&L indicated that Colstrip 3 and 4 transmission-related costs are $276.0/kw[1]. MPC has indicated that its avoided cost calculation includes "bulk transmission costs." (Exh. MPC 1, p. TAL-17).

72. Commission's Existing Policy. In Docket No. 81.2.15 the Commission directed each utility to investigate avoided transmission costs (See Order No. 4865, p. 20).

73. Commission's Decision. The Commission reemphasizes the direction given to the utilities in Docket No. 81.2.15: "The utilities are directed to investigate avoided line losses, avoided transmission costs, and avoided reserve requirements. The Commission intends to expand the role

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1 This $276/kw figure is computed as the difference between $1962/kw for Colstrip 3 and 4, with transmission related costs (See PP&L Data Response No. 17 and TR. Pp. 38, 509), and $1686/kw. The $1686/kw figure was provided by Jerry Rust, of PP&L, to the Commission staff on July 26, 1983; this figure of $1686/kw is derived from the $1821/kw figure supplied by PP&L in a late-filed data request (Letter dated July 13, 1983, Attachment No. 1, p. 1), but corrected per Jerry Rust’s communication to reflect a beginning-, rather than an end-of-year estimate.

of these factors in the calculation of the 1982 standard rates." (Order No. 4865, p. 20). To date the Commission has not received the utilities' analyses of avoided transmission costs. Yet there exists evidence in the record that such costs exist (e. g., PP&L, supra).

74. Due to the absence of analyses by the utilities and intervenors on the issue of avoidable transmission costs, the Commission finds no basis on which to incorporate this cost element into the Commission's avoided cost calculation. This is not to suggest such costs do not exist; however, they are not quantified sufficiently in this proceeding to include them in the avoided cost calculation. In fact, it is not just transmission costs, but also secondary and possibly primary distribution line-related costs that may be avoided, along with all the related transformer and substation costs, as is indicated by PP&L's Long-Run Incremental Cost (LRIC) Study (See MPC Data Response No. 12 and MDU Data Response No. 4).

75. The Commission also finds a correlation between avoided transmission costs and reduced reserve requirements, that is, capacity that is available to provide power in emergency situations. The location of QF's in close proximity to load centers improves system reliability. Just as each utility benefits from reduced reserve requirements due to agreements with other utilities to provide power when emergencies develop, so must each utility benefit from the aggregation of a diverse mix of QF power. The utilities have each indicated their estimates of reserve requirement savings due to utility power pooling agreements (See TR. p. 191; MDU's Late Filed Exh. No. 1, dated July 8, 1983; and PP&L's Late Filed Exh. dated July 13, 1983). In hearing, the MPC indicated that additional reliability -- reduced reserve requirements -- results from a resource mix that includes a large number of small generating plants in place of a single large generating plant:

> Q Thank you. Mr. Gregg, assume for a minute that we have Montana Power Company needs 100 megawatts capacity, do you agree that there is additional reliability if that 100 megawatts is provided from say ten different plants as opposed to one 100 megawatt plant, assuming that all these plants are equally reliable in operating characteristics?
>
> A Individually, you mean?
>
> Q Yes.

A I think I would have to agree with that.

(See TR. p. 193)

Once more, the Commission has yet to receive analyses from any utility on the value of avoided reserve requirements due to the aggregation of QF facilities. While it is clear that a diverse mix of small generating units will likely reduce a utility's reserve requirement, the Commission also recognizes that there will remain a reserve requirement associated with QF power. It is this net difference in reserve requirements on a per kw basis that is unknown.

76. The Commission finds no quantifiable basis to include elements in its avoided cost calculation that reflect avoided transmission and distribution costs and reduced reserve requirements. However, the Commission finds that it is inconsistent to exclude each utility's transmission related avoided costs in the avoided cost calculation, but at the same time, to require each QF to pay for interconnection costs. The resulting avoided cost rates necessarily err on the side of conservatism. These issues will be the focus of additional refinement proceedings in the near future.

Interconnection Standards

77. The Commission's rules require that, if requested, utilities must loan money to QF's for construction of facilities that allow the QF to plug into the utility's grid. There are six issues related to the interconnection requirements: i) subcontracting; ii) construction design; iii) ownership and maintenance; iv) finance charges for capital; v) finance charges for operation and maintenance (O&M); and vi) amortization length. Each of these will be discussed in turn.

78. Commission's Existing Interconnect Policy. In Docket No. 81.2.15 the Commission relied upon the existing administrative rules [ARM 38.5.1904(2)(c)] as a guide to contract development. The Commission only emphasized that if a utility provides financing for interconnection facilities, the QF must reimburse the utility over a reasonable period of time (See Order No. 4865, Finding No. 27).

i. Subcontracting

79. Parties' Positions. MPC testified that it had no objection to a QF contracting with someone other than the utility to construct interconnection equipment if the interconnection is for exclusive use of the QF, and so long as the interconnect is on the QF side of the interconnection (See MPC Exh. 1, p. RFC-9). MDU prefers that a QF construct the interconnection except if MDU property is involved, in which case the utility must at least supervise interconnection activity (See MDU Exh. 1, pp. 9, 10).

PP&L stated the following in its direct testimony:

> Q. "D. Should QF's be allowed to contract with independent electric contractors to provide an interconnection?"
>
> A. QFs are responsible for providing all facilities from generation to the point of delivery to the utility. The utility, in protecting its system and service to other customers, must supervise all construction on, or changes to, the facilities on its side of the point of delivery.
>
> Should a QF find it possible to contract for construction on the utility's system at a cost below the utility's, that contractor must (1) be acceptable to the utility, and (2) work under the utility's direct supervision. Finally, the facilities must be inspected and approved by the utility before being placed in service. (PP&L Exh. 1, p. 5)

Ultrasystems (UI) testified that QF's should have several contracting options including: 1) QF built; 2) contractor built; and 3) utility built. UI states, however, that utility design specifications, in constructing the interconnection facilities, must be adhered to (See UI Exh. 1, p. 4). REDA testified that subcontracting will encourage competitive bidding and lead to reduced costs (REDA Exh. 1, p. 4). Of course, if such is the case, the utility could also use an independent contractor.

80. Commission's Decisions. For purposes of this and the following issues the Commission reiterates the provisions of ARM 38.5.1901(2)(d). That rule defines "Interconnection costs" to include all costs; that is, there is no distinction between special and ordinary interconnection costs: Interconnection costs include costs for interconnection facilities and special or additional facilities i.e., control and protective devices and facilities to accommodate utility meter(s) [See ARM 38.5.1904(2)(a)]. Also, the "point-of-interconnect" means the point where a QF

interconnects with the utility's existing grid system. The point-of-delivery will correspond with the point-of-interconnection only if power is metered at the point-of-interconnection.

81. The Commission finds that subcontracting of any interconnection facilities (special or ordinary), on the QF's side of the point of interconnect, shall be allowed. If a QF or a QF's contractor can construct any interconnection facilities on the QF's side of the point-of-interconnect at lesser cost than the utility, then the QF should be allowed to do so. The QF, however, must build to utility design specifications. Utility supervision is permitted. The utility must, of necessity, provide to the QF a definitive breakdown of all interconnection related costs, specifying the manufacture of materials used, and labor hours and costs for each distinct portion of the interconnect.

ii. Construction Design

82. Intervenors' Positions. Evident from the record is a possible wide range of interconnection requirements (See MPC Exh. 1, p. RFC-8, PP&L Exh. 1, p. 5 and REDA Exh. 1, p. 3). UI states that the interconnection should be built to utility design specifications (UI Exh. No. 1, p. 4), while REDA requests that the Commission set a standard for low-voltage metering and disconnects (REDA Exh. 1, D. 3)

83. Commission's Decision. The Commission finds that all interconnection facilities must be built to utility design specifications. Interconnection standards must comply with the Commission's rules [ARM 38.5.1907(1) through (5)]. The design specifications adopted by the utilities should, however, minimize the total costs of all interconnection facilities to the extent possible. To this end, the Commission emphasizes that QF's must be responsible for any and all costs up to the point-of-interconnection, including line losses. If, for example, a QF prefers metering at the point-of-generation, then the QF must assume responsibility for the line losses occurring from this point up to the point of interconnection with the utility. This line-loss responsibility is similar to agreements that the utilities have for purchased power; that is, a utility's purchase rate is for power at a point-of-delivery and includes mutually agreed upon wheeling costs up to this point.

84. The Commission finds that an acceptable means of resolving design specification conflicts/disagreements between a QF and a utility, is arbitration. Design specification issues, for

which arbitration is an appropriate means of conflict resolution, include, for example, line loss estimates for just the interconnection facilities, metering costs, voltage level, and points of interconnection and metering: Generally, any interconnection conflict may be arbitrated. The Commission also finds that the arbitrator must be mutually agreed upon by the QF and utility. The party that loses the arbitration decision must remunerate the arbitrator for the total costs of arbitration.

iii. Ownership & Maintenance

85. Intervenor Positions. The MPC argues that the QF should own the interconnection facilities unless constructed by the utility, in which case the utility retains ownership (MPC Exh. 1, p. RFC-10). The MPC's long-term power purchase agreement states that only the MPC will work on, own, and operate and maintain interconnection facilities on the MPC's side of the point-of-interconnection (Ibid., Exh. RFC-1, Section 8.3). MDU testified that ownership of interconnection facilities varies, depending on which side of the point-of-interconnection one refers to. The utility owns the facilities on its side and the QF owns the facilities on the other side (MDU Exh. 1, p. 10). PP&L has testified that "...all facilities on the utility's side of the point of delivery must remain an integral part of the utility's system" (PP&L Exh. 1, p. 6). UI has stated that, "To the extent a QF builds, or contracts to have built for it, interconnection facilities to utility specifications, the QF should own the facilities. If the QF opts to have the utility construct the interconnection facilities at the QF's expense the utility should retain ownership of the facilities until paid for by the QF" (UI Exh. 1, pp. 5, 6). In its Rebuttal Brief UI clarified its position on cost burden and ownership of interconnection upgrades on the utility's side of the point-of-interconnection stating:

> If that interconnection in turn causes the utility to upgrade its transmission system then MDU is correct that the obligation to pay for such upgrades rests with the QF while ownership of those upgrades remains with the utility. (UI Rebuttal Brief, pp. 25, 26)

86. Commission's Decision. The Commission finds that ownership of any interconnection facilities shall be based on whose side of the point-of-interconnect the facilities are located. The QF is responsible for maintenance of its facilities. If, however, a utility is willing, the

Commission finds that the utility may maintain the QF's portion of an interconnect for a mutually agreed upon fee. The utility's portion of the interconnect may only be maintained by the utility. As a point of clarification, the Commission emphasizes that upgrades required for interconnection to the utility grid system, at the time that the QF interconnects, shall be the cost burden of the QF. Later upgrades to maintain reliable and dependable service are solely the utility's responsibility (See Finding No. 57 of Order No. 4865).

iv. Finance Charge for Capital

87. Intervenors' Positions. The MPC states that a capital charge for interconnection facilities should recover the following costs: an appropriate allocation of general and common plant, debt and equity costs and income taxes (MPC Exh. 1, p. RFC-12). PP&L has testified that the capital charge rate should equal the Morgan Guarantee Trust Company Prime Rate plus 1 percent (See PP&L Exh. No. 1, p. 6, and PP&L Data Response No. 10). MDU has stated that the appropriate finance charge is its current finance charge (MDU Exh. 1, p. 10, and TR. p. 121).

88. In a related matter the MPC has testified that a QF should receive some sort of refund if, subsequent to its interconnection, another QF or utility customer interconnects to facilities paid for by the QF (MPC Exh. 1, p. RFC-11, and Exh. RFC-1, Section 8.5).

89. Commission's Decision. Regarding an appropriate finance charge for capital the Commission finds that a charge, reflecting the Company's overall incremental cost of capital, is appropriate. The same carrying charge should apply regardless of whether the interconnection facilities are on the QF's or utility's side of the interconnect.

90. The Commission finds that there should be a sharing of the interconnect costs between initial QF's and, subsequent QF's or utility customers. The Commission leaves to the utilities the individual design of such refund provisions.

v. Operation and Maintenance Annual Charge

91. Intervenors' Positions. The MPC has testified that an annual operation and maintenance (O&M) charge must cover the average O&M costs for similar facilities, including charges for ad valorem taxes, insurance and administrative and general costs. The MPC further states

that if the interconnect facilities are on the utility's side of the point-of-interconnect, and for exclusive use of the QF, the QF should bear the O&M fees (See MPC Exh. 1, pp. RFC-11, 12). PP&L indicates that an 8 percent per annum charge should apply for O&M expenses (PP&L Exh. 1, p. 6). REDA suggests that utility provided O&M be available on some sort of time and materials basis (REDA Exh. 1, p. 4).

92. Commission's Decision. Depending on what side of the point-of-interconnect the interconnect facilities are located, two circumstances arise that require O&M annual charges. The Commission finds acceptable the following O&M charge options for the two above circumstances: 1) a recurring charge based on the cost components identified by the utility; and 2) a nonrecurring time and materials charge. The utilities must provide cost estimates to QF's for each of these items.

93. Regarding option 1) above, the Commission is concerned with PP&L's proposed 8 percent charge versus the MPC's recurring charge for O&M (actual cost or 4.31 percent). In a letter addressed to the City of Livingston (to Mr. Ed Stern, dated July 28, 1983) the MPC (Mr. Richard F. Cromer) has indicated that an annual recurring charge of 4.31 percent shall apply. This rate, in turn, covers O&M (1.94%), ad valorem taxes (2.07%), and insurance (0.30%). Each utility shall provide the Commission the total O&M charge (percent), broken down into its constituent parts, that it intends to apply towards interconnection facilities on either side of the point-of-interconnect. This information should be provided when each utility's avoided cost rates are updated pursuant to this order. The Commission will carefully scrutinize the charges filed by each utility.

vi. Amortization

94. Intervenors' Positions. The intervenors have proposed a variety of periods over which financing for interconnection facilities will be repaid. The MPC prefers a period equal to the useful life of the plant or the length of QF contract, whichever is shorter (MPC Exh. 1, p. RFC-13). PP&L prefers a period equal to one-half the contract term but with a five year limit (PP&L Exh. 1, p. 7). MDU prefers to leave the issue to negotiation (MDU Exh. 1, p. 11). UI testified that the amortization period should be the same as for similar utility equipment (UI Exh. 1, p. 6). REDA stated that, "The

life of the contract would be the best amortization period for all accounting treatments. . ." (REDA Exh. 1, p. 5).

95. Commission's Decision. The Commission finds merit in basing the amortization period on the life of the QF contract or the life of similar utility equipment, whichever is shortest.

The MPC's Allegation of Double Counting

96. Summary of Issue. In the hearing MPC claimed that the Commission's avoided cost rate methodology double counts resource economic value (TR. pp. 508, 509). In its Opening Brief the MPC states:

> F. PSC must not "double count resource economic value
>
> The PSC's methodology overstates the installed cost of resources. Under the methodology, a double counting in economic value occurs. "The double counting is that you account once for the economic cost of the plant through AFUDC and in addition escalate (construction expenditures plus AFUDC) upward." TR 508-509. The result is that QF rates are based on plant costs not related to (and higher than) those costs of the plant which a ratepayer would experience. The ultimate impact is an overstimulation of QF resources relative to the utility resources, which are to be the basis of avoided cost, and higher rates than would have been the case had utility plant been placed in rate base. (MPC Opening Brief, pp. 24, 25)

97. Commission's Existing Policy. This issue was aired in the previous docket. In Order No. 4865 (Finding of Fact No. 44) the Commission directed each utility to use constant contract year dollars. This direction was reemphasized in Order No. 4865a (Finding of Fact No. 48). In Order No. 4865b, the Commission once more emphasized the use of constant contract year's dollars, pointing out the flaw of using the summation of nominal cash flows.

98. Commission's Decision. The Commission agrees, in part, with the MPC statement that "...QF rates are based on plant costs not related to (and higher than) those costs of the plant which a ratepayer would experience. (MPC Opening Brief, p. 25). Accounting costs and economic

costs are not the same[1]. The Commission's economic cost estimate of Colstrip 3 and 4, however, is related to and derives from, the Company's actual' accounting costs. The Commission once more finds that the intent of the Public Utility Regulatory Policies Act (PURPA) was to base avoided cost rates on economic costs and not accounting costs.

The MPC's Capacity Payment Adjustments

99. MPC proposes two changes to the existing capacity payments (See MPC Exh. 1, Exh. No. RFC-1, Appendix A). The first proposal effectively caps the value of capacity payments by assuming a maximum 70 percent availability factor. The second proposal involves paying for capacity on the basis of an 11 month average of a QF's best performance.

100. Commission's Current Practice and Decision. Presently, QF's receive a long-term capacity payment that assumes an 85 percent availability factor (See Appendix B of Order No. 4865). Additionally, QF's receive capacity payments on a best 15-minute performance basis.

101. The Commission finds that QF's shall continue to receive capacity payments in relation to an 85 percent availability factor. In addition, the Commission finds that the capacity payment should vary relative to an 85 percent availability factor. That is, if a QF's actual capacity exceeds 85 percent, the capacity payment shall reflect this added value. This decision is based on MPC's that the value of QF power indeed varies with its availability:

Recross, by Mr. Nelson:

1

Where accounting dollars represent historic cash flow and AFUDC together with discounted future cash flows and AFUDC. Economic costs are accounting costs collapsed into a constant contract year’s dollars using historic (actual) and forecast escalation rates.

Q Mr. Gregg, I believe you just testified in response to questions from Mr. Roberts that basically as the availability of the qualifying facility increases beyond the availability figure of the existing plant, the value of the qualifying facility's power increases, is that correct?

A All other things being equal, yes. (TR. p. 279)

102. The Commission finds merit in the MPC's proposal to make capacity payments on the basis of the 11 best months of performance. Each utility should adopt this concept. This modification will result in QF's being paid a capacity payment in relation to actual performance on an average basis versus the existing payment which is received for a single 15 minute highest performance basis.

Environmental Impacts

103. Summary of Issue. The Commission received testimony from the Montana Department of Fish, Wildlife and Parks (FW&P) expressing concern over the relation between the proliferation of small hydro projects on Montana's streams, and the Commission's avoided cost rates (See FW&P Exh. 1).

104. In a related matter, the MPC stated in its opening brief that the Commission is not exempt from the Montana Environmental Policy Act (MEPA) and requests that an "...appropriate environmental assessment must be undertaken." (MPC Opening Brief, p. 29). See Conclusion of Law No. 5 for a discussion of this issue.

105. Regarding the FW&P's concern, it is worth noting that it is this Commission's charge to develop avoided cost rates based on utility costs, and not to internalize environmental costs resulting from QF development. The Commission acknowledges that this charge does not internalize all costs e.g., environmental costs such as dewatering Montana creeks, air pollution due to cogeneration, and noise pollution from wind generators. Nor does the Commission's method internalize any positive production externalities.

106. As a possible solution to the problem identified by FW&P, the Commission prefers to have, and is willing to endorse, the Montana Department of Fish Wildlife & Parks as the agency whose position on environmental damage caused by proposed dams, should determine whether an

FERC permit is granted. There is no other agency more acutely aware of the ecological consequences of small hydro development in Montana.

107. The Department of Health and Environmental Sciences is similarly charged with the duty of regulating environmental impacts relating to air and water pollution that might result from construction of thermal cogeneration projects.

108. The Commission fully supports the proposition that QF's face the full legitimate environmental costs associated with their development.

Ratemaking Treatment

109. Summary of Issue and Commission's Decision. PP&L requests the Commission to promulgate regulations "...which require the Commission to allow as prudently incurred purchase power expenses amounts paid to QF's pursuant to agreements between the utilities and QF's entered into under prices approved by the Commission" (PP&L Opening Brief, pp. 7, 8). PP&L also "...requests the Commission to promulgate regulations allowing Pacific to allocate directly to Montana electric rates any Commission imposed contract terms or avoided cost prices found imprudent by another jurisdiction." (Ibid., p. 8). In Docket No. 81.2.15, the Commission found that expenses associated with defaults would be treated as valid utility expenses for ratemaking purposes. The same assurance is given here in response to PP&L's first request. Although the Commission sympathizes with the motives under the general unwillingness of utilities to purchase energy from small power producers.

Billing Alternatives

111. In Docket No. 81.2.15, the Commission found that QF's should be offered the following billing alternatives: 1) simultaneous sale and purchase; 2) net billing. Whatever the alternative chosen, the Commission also found that utilities should develop simple billing procedures. (Order No. 4865, p. 23) Because no party contested or discussed these findings, there is no reason to change them, and they are incorporated as part of this order.

Force Majeure

112. On reconsideration in Docket No. 81.2.15, the Commission found that force majeure clauses should not go beyond standard contract language. (Order No. 4865a, p. 14) The finding was in response to proposed contract provisions which contained exceptions for lack of motive force. In this docket, MPC's proposed contract contains a force majeure provision, that exempts from coverage nonavailability of fuel, inadequacy of water supply, lack of motive force and forced outages. PP&L's and MDU's contracts comply with the Commission's previous order.

113. The Commission continues to believe that an unqualified force majeure clause is sufficient to adequately protect all parties. Under such a provision, the exceptions contained in MPC's contract would usually not be considered good cause to invoke a force majeure clause. However, there might be occasions where loss of motive force was caused by unforeseeable events such as earthquakes. The fact that neither MDU nor PP&L feel the need to include exceptions in their force majeure clauses in their contracts, and the fact that MPC has not provided evidence to support its provision, reinforces the Commission's previous findings.

Insurance Requirements

114. Summary of Issue. There are two aspects involved in the issue of what kind of insurance provisions should be allowed in standard contracts: 1) whether utilities should be allowed to raise coverage requirements subsequent to signing of the contract; 2) whether utilities should be allowed to require a QF to maintain property insurance, with the utility a named insured, up to the total value of the QF.

115. In Docket No. 81.2.15, the Commission concluded that it was reasonable for utilities to require general liability insurance with provisions for additional coverage if required in good faith. The Commission further found that property insurance with the utility as a named insured was unnecessary. (Order No. 4865, p. 28)

116. Parties' Positions. MPC's contract contains provisions allowing the utility to increase insurance coverage for property insurance, and stated its intent to add a similar requirement for liability insurance. (MPC Exh. 2, REF-5) PP&L has a similar provision, except that it includes a

required two year notice before the provision can be invoked, and the utility can require no more than a 15 percent comparable provision. UI claimed that the increase in coverage provision should be forbidden, and that limits should be fixed at the outset. (UI Exh. 1, p. 12) The only support for the provision came from MPC, which claimed that it should be able to reflect the effects of inflation and claims experience in the insurance provisions. (MPC Exh. 2, RFC-5)

117. Commission's Decision. MPC's testimony on this issue is not overwhelming. However, the Commission recognizes that altering insurance coverage to reflect changing economic conditions and claim experience is accepted business practice. PP&L's insurance provision provides a reasonable approach: It gives QF's time to prepare for increased insurance costs and also limits the QF's potential exposure. In addition, if a QF disagrees with a utility's conclusion that more insurance is necessary, the two year notice gives the QF ample time to appeal to an arbitrator or to the Commission to determine whether the requirement is reasonable under the circumstances.

The logic which requires the possibility of upward adjustments applied equally to downward adjustments. Therefore, the contracts must make some provision for QF's decreasing insurance coverage if economic conditions or claims experience so warrant.

118. Parties' Positions. PP&L, MDU, and MPC include in their contracts insurance requirements that provide for property insurance up to the value of the QF's property. MPC's reasoning seems to be in part that, since it will rely on the QF's capacity and energy, it must be assured that it can rebuild the QF's facility so that it can continue to receive the facility's output. (MPC Exh. 2, RFC-6) MDU's and PP&L's cross-examination seems to suggest that their insurance requirements are designed to assure that levelized capacity payments are reimbursed. MPC makes this explicit (MPC Exh. 2, RFC-6) UI contends that the provision is inappropriate and the purpose of this insurance, however, it is clear that it should be required only with levelized contracts, and the utilities are directed to limit such provisions to contracts that levelize payments.

121. The Commission does not agree with MPC that damages it might suffer necessarily are commensurate with the cost of the facility. They might be more or less, and can be collected in regular legal proceedings rather than through insurance provisions that could place an undue burden on QF's.

Liquidated Damages

122. In Docket No. 81.2.15, the Commission found on reconsideration and based upon testimony from MDU, that liquidated damages provisions were unnecessary because actual damages could be easily determined with actual default. (Order No. 81.2.15, p. 13)

123. Neither PP&L nor MDU has a liquidated damages clause in their proposed contracts. MPC's contract, however, does contain such a provision. The intent of the provision is to assure MPC's ratepayers that proper value is received for capacity payments made. (MPC Exh. 1, RFC-5) UI opposes any liquidated damages provision on the grounds that such a provision strongly suggests a penalty.

124. MPC's liquidated damages provision reflects, to some degree, the Commission's original opinion stated in Docket No. 81.2.15 (Order No. 4865a, p. 36) that damages would depend on loss of capacity with insufficient notice. MPC justifies its provision in part on the grounds that it is difficult to ascertain damages for early termination at the commencement of the contract (MPC Br., p. 13).

125. The Commission continues to believe that liquidated damages provisions should not be included in contracts. Actual damages might well be either more or less than those provided for in MPC's contract. Since, according to MDU, they can be readily determined at time of default, both the QF and the utility will benefit by leaving the issue of damages open until the time of default. This approach is consistent with MPC's claim that damages are difficult to determine at the beginning of the contract. In any case, the claim is irrelevant; it is the Commission's view that liquidated damages would be justified only if damages could not be determined at the time the contract is breached.

126. Because of the uncertainty of the appropriate level of damages with breach, a liquidated damages provision could, in fact, result in an undercollection of damages by the utility. Further, the Commission believes that insurance provisions adequately address MPC's concerns about capacity payments.

Government Regulation as Grounds for Termination

127. In Docket No. 81.2.15, MPC's contract contained a provision that made government regulation grounds for contract termination without penalty. The Commission forbade inclusion of such a provision.

128. In this Docket, none of the utilities' contracts contain such a provision. However, in its testimony MPC states that if the Commission doesn't accept its proposed contract, it will insert such a provision. (MPC, Exh. 2)

129. UI opposes a government regulation provision. (UI Exh. 1, p. 24) According to UI, government regulation should not be grounds for termination unless performance is impossible, in which case, the force majeure clause can be invoked.

130. The Commission agrees with UI's analysis. In addition, such clauses are viewed with extreme suspicion by financial institutions, and can make QF projects unfinanceable. As the Commission noted in Order No. 4865: "The fact that there is no mutuality involved in making such a determination suggests that such a clause begs contention and promotes uncertainty as to party responsibilities." (Order No. 4865, p. 39) MPC has failed to address these valid concerns in such a way that there are sufficient grounds to reverse the Commission's previous decision.

Indemnity Clauses

131. UI challenged MPC's proposed indemnity clauses as being overly broad in its provision for consequential damages, claiming that it covers unforeseeable events (UI Exh. 1, p. 12). MPC responded that consequential damages are by law, limited to foreseeable events. (MPC Exh. 2, RFC-8) All parties seem to agree that damages permitted by law should be neither limited nor extended.

132. This issue seems to be a problem of semantics and legal interpretation. Because UI has not challenged MPC's legal claims regarding damages under relevant Montana law, the Commission accepts this interpretation. The Commission agrees with the parties that indemnity clauses should neither limit nor expand the scope of damages permitted by Montana law.

Curtailment

133. UI claims that MPC's provision for curtailing purchase of QF power is overly broad and does not comply with the Commission's regulations. (UI Exh. 1, p. 28) The contention was not disputed by the Company. On the face of it, the provision does seem to allow curtailment beyond the type contemplated by the Commission's rules, and the Commission so finds. MPC should alter the provision to bring it into conformance with the Commission's regulations.

Good Faith Negotiations

134. Numerous witnesses testified that they believed MPC failed to negotiate with them in good faith.

135. In response to these accusations, MPC admitted that there had been confusion and uncertainty in its implementation of the Commission's previous order, and that there had been some serious philosophical disagreements with the laws themselves. There was a period of time when contracts were simply not being offered.

136. In response to these claims and counterclaims, Commission staff asked a number of witnesses to list criteria by which the Commission could determine whether there were good faith negotiations by all parties. In the Commission's judgment, no witness offered particularly helpful suggestions.

137. The Commission recognizes that individual negotiations will vary widely depending on the size and complexity of the project, how well developed the prospective QF's plans are when the utilities are first approached, etc.

138. Rather than try to establish set criteria that might, in fact, hamper negotiations, the Commission finds it appropriate to require the utilities to document the progress of negotiations. This documentation should include internal memos summarizing contracts with a particular prospective QF. Utilities should, following any meeting or conversation which explores specifics of a contract, write a follow-up letter to the prospective QF summarizing its understanding of the status of the negotiations, who is responsible for further actions, and when those actions should be taken. If this letter does not reflect the prospective QF's understanding of the status of negotiations, it has the obligation to respond with corrections.

139. While this procedure might sound onerous, the Commission believes it is simply good business practice. More importantly, when implemented, it should eliminate the disputes over who said what, when and where that are contained in this docket.

140. The Commission does not wish to become involved in the negotiating process, nor does it wish to establish hard criteria for negotiations. However, in order to discharge its obligations under both state and federal law, it must remain ready to enter the negotiating arena if necessary to assure that cogeneration and small power production plants are encouraged.

Rules

141. As part of its order initiating this proceeding, the Commission invited suggestions on its rules governing sales by QF's to utilities, ARM 38.5.1901 et seq. Several comments were received. The Commission will review these suggestions in the near future in a separate rulemaking proceeding.

CONCLUSIONS OF LAW

1. Montana-Dakota Utilities Company, Montana Power Company and Pacific Power & Light Company are public utilities within the meaning of Montana law, Sections 69-3-101 and 69-3-601(3), MCA.

2. The Commission properly exercises jurisdiction over the rates, terms, and conditions for the purchase of electricity by public utilities from qualified cogenerators and small power producers. Sections 69-3-102, 69-3-103 and 69-3-601 et seq., MCA. Section 210, Pub. L. 97-617, 92 Stat. 3119 (1978).

3. The rates the Commission has directed the utilities to file are just and reasonable to Montana ratepayers as they reflect each utility's avoided energy and capacity costs.

4. The objective of encouraging cogeneration and small power production is promoted by the rates, terms, and conditions established by this order.

5. The Commisson's ratemaking decisions are exempt from the requirements of Montana's Environmental Policy Act, 75-1-101 et seq., MCA. The Commission interprets 75-1-201,

MCA, as an exception that applies to the Commission's ratemaking activities. This proceeding is designed to establish rates, and, thus, is included in the exception.

ORDER

1. MDU, MPC and PP&L shall develop and file rates pursuant to the Commission's findings in this order. Such rates shall be filed within 30 days.

a) The rates for short-term contracts shall be computed pursuant to Commission direction in Order No. 4865.

b) The utilities shall compute a Base Long-Term Rate pursuant to the findings in this order. Such base rate shall be updated each June 1 for the subsequent contract year.

c) The utilities shall use a real carrying charge rate with each of the base- and peak-load capital cost estimates. The utilities shall all use a 1.083 line loss factor and apply this factor to all terms of the Commission's Base Long-Term Rate, as well as to the two long-term options.

d) PP&L and MPC shall use Colstrip 3 and 4 in computing base-load capital costs. MDU shall use Antelope Valley System No. 2. Each utility shall use a combustion turbine as the peak-load facility. These resources shall serve as the basis of avoided cost rates until such time the Commission chooses to substitute other resources.

2. Each utility shall submit to the Commission and all parties detailed work papers showing the development of discount rates, real carrying charges fixed and variable O&M (See Finding No. 33 of Order No. 4865).

a) The development of carrying charges shall be exhaustive with a clear breakdown of the capital structure and all other components. All methodological steps must be shown.

b) The development of incremental discount rates shall be equally exhaustive.

c) The utilities must each develop and file levelized avoided cost rates for the contract lengths indicated in Finding of Fact No. 55.

3. Each utility shall be prepared, in each subsequent electric rate case, to verify with detailed working papers the escalation rates provided each June 1 for the escalating long-term rate option.

4. All motions and objections not ruled upon are denied.

DONE AND DATED this 7th day of November, 1983 by a vote of 5-0.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.

THOMAS J. SCHNEIDER, Chairman

JOHN B. DRISCOLL, Commissioner

HOWARD L. ELLIS, Commissioner

CLYDE JARVIS, Commissioner

DANNY OBERG, Commissioner

ATTEST:

Madeline L. Cottrill
Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten days. See 38.2. 4806, ARM.

GLOSSARY SOURCES

A. Glossary of Electric Utility Terms, Prepared by the Statistical Committee of the Edison Electric Institute - EEI Publication, No. 70-40.

B. Northwest Power Planning Council, Regional Conservation and Electric Power Plan, Draft, January 26, 1983.

C. Rosalie T. Ruegg and G. Thomas Sav, The Microeconomics of Solar Energy in a publication by Dr. Jan F. Kreider and Dr. Frank Kreith, Solar Energy Handbook. 1981. McGraw-Hill Book Company.

D. Harold E. Marshall and Rosalie T. Ruegg, Simplified Energy Design Economics, U.S. Department of Commerce, NBS Special Publication 544, January, 1980.

E. Public Utility Regulatory Policies Act, 18 C.F.R. 292.101(b)(6), and 292.304(e)(2)(vi).

F. Technical Assessment Guide, Prepared by Technology Evaluation Group of the Electric Power Research Institute's Planning and Evaluation Division. P-2410-SR, May, 1982.

G. Public Law 95-617 - November 9, 1978.

H. Black's Law Dictionary, Fifth Edition, West Publishing Co. (1979).

GLOSSARY

Availability Factor — Is the percent of time that a combustion turbine is assumed to be available. In Docket No. 81.2.15 (Order No. 4865, Finding of Fact No. 28), the Commission assumed that combustion turbines will be available 85 percent of the time.

Avoided Costs — The incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source. E

Capacity Factor — The total energy output over a period of time in hours divided by the product of the period hours and the unit capacity. The capacity factor can be computed on either a net or gross basis. F

The ratio of the average load on a machine or equipment for the period of time considered to the capacity rating of the machine or equipment. A

Capacity, Rated	The maximum capacity which a generating unit can sustain over a specified period of time. The capacity may be stated as net or gross. F
Capacity, Thermal	The rating of a thermal electric generating unit or the sum of such ratings for all units in a station or stations. A
Carrying Charge Factor (Rate)	The amount of revenue per dollar of investment that must be collected from customers in order to pay the carrying charges on that investment. The carrying charge factor (rate) is expressed as a decimal that is multiplied by the original investment to obtain a dollar amount. The carrying charge rate can be a present value or levelized quantity, over a specified period of time (up to the book life), or an annual quantity in a specific year of life. F Carrying charges are an obligation incurred when the plant is placed in service, and they remain an obligation until the plant is retired at the end of its life. The only way to avoid a carrying charge obligation is to not commit funds for the plant investment, because once the investment is made, the carrying charge must be collected as revenue regardless of how much or how little the plant is actually used until the plant is fully depreciated. F
Carrying Charges	The revenue needed to support an investment and equal to the sum of Return on Debt Return on Equity Income Taxes Book Depreciation Property Tax Insurance. F
Constant Dollar Analysis	An analysis made without including the effect of inflation although real escalation is included. F
Constant Dollars	Values expressed in terms of the general purchasing power of the dollar in the base year. Constant dollars do not reflect price inflation. D
Current Dollar Analysis	An analysis that includes the effect of inflation and real escalation. F
Current Dollars	Values expressed in terms of actual prices of each year. Current dollars reflect price inflation. D
Demand	The rate at which electric energy is delivered, expressed in units of power, such as kilowatts, at a given instant (indicated) or averaged (integrated) over

a designated period of time. In the utility industry, it is common to express demand as one hour integrated. F

Discount Rate The discount rate to be used in present value calculations is related to the weighted cost of capital. Most utilities use a discount rate equal to the weighted cost of capital, but some use an "after tax cost" equal to the weighted cost of capital less the tax rate times the debt return. Neither method is completely appropriate under all circumstances for all electric utilities. A discount rate equal to the weighted cost of capital has been selected for use at EPRI because of its more general use in the electric utility industry. F

To apply the discount formulas or factors, it is necessary to select a discount rate. The discount rate should reflect the investing person's or firm's time preference for money (or more accurately, the resources money can buy). Apart from inflation, time preference reflects the fact that (1) money in hand can be invested to earn a return and (2) money borrowed requires interest to be paid. Of these two factors, the former, often called "the opportunity cost," is generally predominant in establishing a discount rate. C

The rate of interest reflecting the time value of money that is used to convert benefits and costs occurring at different times to equivalent values at a common time. D

Discounting — A technique for converting cash flows that occur over time to equivalent amounts at a common point in time. D

Energy — That which does, or is capable of doing, work. Energy is measured in terms of the work it is capable of doing. Electric energy is commonly measured in kilowatt-hours. B

Energy, Electric — As commonly used in the electric utility industry, electric energy means kilowatt-hours. A

Escalation, Apparent — The total annual rate of increase in cost. The apparent escalation rate includes the effects of inflation and real escalation. F

Escalation, Real — The annual rate of increase of an expenditure that is due to factors such as resource depletion, increased demand, and improvements and in design or manufacturing (negative rate). The real escalation rate does not include inflation (see Escalation, Apparent). F

Force Majeure — In the law of insurance superior or irresistible force. Such clause is common in construction contracts to protect the parties in the event that a party of the

	contract cannot be performed due to causes which are outside the control of the parties and could not be avoided by exercise of due care. H
Incremental Costs (Energy)	The increase in cost of generating or transmitting additional electricity above some previously determined base amount. A
Inflation	A rise in the general price level resulting from a decline in the purchasing power of the dollar. D
Kilowatt (kw)	The electrical unit of power which equals 1, 000 watts. B
Kilowatt- Hour (kwh)	A basic unit of electrical energy which equals one kilowatt of power applied for one hour. B
Levelized Cost	The present value of a resource's cost (including capital, interest, and operating costs) converted into a stream of equal annual payments and divided by annual kilowatt-hours saved. B
Levelized Rate	A rate that is higher than the avoided cost in the early years of the contract and lower in the latter years.
Long- Run Incremental Costs	In contrast to short-run incremental costs (SRIC), long-run incremental costs (LRIC) are costs that result from either replacing or augmenting existing productive capability. In the long-run an economic agent e.g., an electric utility, has the option of building a new electric plant. In the short-run this option does not exist. LRIC are costs that an economic agent plans to incur or avoid in the future.
Loss (Losses)	The general term applied to energy (kilowatt-hours) and power (kilowatt) lost in the operation of an electric system. Losses occur principally as energy transformations from kilowatt-hours to waste heat in electrical conductors and apparatus. A
Average	The total difference in energy input and output or power input and output (due to losses) averaged over a time interval and expressed either in physical quantities or as a percentage of total input .
Energy	The kilowatt-hours lost in the operation of an electric system.
Line	Kilowatt-hours and kilowatts lost in transmission and distribution lines under specified conditions.

Peak Percent	The difference between the power input and output, as a result of losses due to the transfer of power between two or more points on a system at the time of maximum load, divided by the power input.
System	The difference between the system net energy or power input and output, resulting from characteristic losses and unaccounted for between the sources of supply and the metering points of delivery on a system.
Nominal Aggregate Capacity Credit	In Docket No. 81.2.15 (Order No. 4865, Finding of Fact No. 28), the Commission found that QF's should receive a nominal capacity payment reflective of the benefit to a utility and its ratepayers that results from aggregating QF power. The Commission assumed a 42.5 percent availability level for the aggregation of QFs relative to a combustion turbine's 85 percent availability factor.
Portfolio Effect	The portfolio effect is generally meant to be the benefit to a utility and its ratepayers that results from aggregating QF power (also, see the above definition for Nominal Aggregate Capacity Credits).
Power (Electric)	The term rate of generating, transferring or using electric energy, usually expressed in kilowatts. A
Firm	Power or power-producing capacity intended to be available at all times during the period covered by a commitment, even under adverse conditions. A
Nonfirm	Power or power-producing capacity supplied or available under an arrangement which does not have the guaranteed continuous availability feature of firm power. A
Nonfirm Energy	Energy which is subject to interruption or curtailment by the supplier. Same as secondary energy. B
Firm Energy	Energy considered assured to the customer to meet all load requirements. It is that energy available based on the worst case, critical planning period. B
PURPA	(The Public Utility Regulatory Policies Act of 1978) The Congress finds that the protection of the public health, safety, and welfare, the preservation of national security, and the proper exercise of congressional authority under the Constitution to regulate interstate commerce require --

(1) a program providing for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers,

(2) a program to improve the wholesale distribution of electric energy, the reliability of electric service, the procedures concerning consideration of wholesale rate applications before the Federal Energy Regulatory Commission, the participation of the public in matters before the Commission, and to provide other measures with respect to the regulation of the wholesale sale of electric energy,

(3) a program to provide for the expeditious development of hydroelectric potential at existing small dams to provide needed hydroelectric power,

(4) a program for the conservation of natural gas while insuring that rates to natural gas consumers are equitable,

(5) a program to encourage the development of crude oil transportation systems, and

(6) the establishment of certain other authorities as provided in title VI of this Act. G

Running Costs	(See definition for System Lambda)
Short-Run Incremental Costs	In contrast to long-run incremental costs (LRIC), short-run incremental costs (SRIC) are costs that an economic agent such as an electric utility incurs from operating, for example, a fixed amount of plant at various levels of output. That is, the amount of plant is fixed and can neither be replaced or augmented. That is, SRIC are the costs that would be incurred (avoided) by operating (not operating) an existing plant.
System Lambda	This concept includes fuel costs, variable operation and maintenance expenses, fuel inventory and fuel working capital requirements. These components are also refined to as short-run variable operating costs.

SUPPLEMENTAL OPINION

BY

John B. Driscoll, Commissioner

November 1, 1983

These comments pertain to (1) the developing relationship between regulator and regulated in this matter of "avoided cost determination," and (2) an opportunity I see for mutually beneficial cooperative action involving independent power suppliers, new large electric loads, the utility and this Commission.

This order is our best effort to lay fair and understandable ground rules for the sale of small power production and industrial cogeneration to our jurisdictional utilities. Montana Power, Montana-Dakota Utilities, and Pacific Power and Light, as monopoly suppliers, typically press for prices higher than we usually allow. Similarly, we have seen those same companies, as "monopsonist buyers" in this docket, offer every conceivable reason for depressing the market and conditions for decentralized power production. This is to be expected and part of the normal course of regulation. Now that we have heard and pondered those many points, some of which have been incorporated into this order, it is clearly time for the regulated companies to comply. As well as any group, the trained and able management of the respective utilities must recognize the theoretically beneficial role of having a regulating body inject the discipline of the market into an otherwise monopsonist situation. Once this decision's process is complete, dilatory tactics will be wasteful of time, effort and good will. Rather, it would be wiser to withhold any strongly held opinions until the next opportunity formally afforded for adjustments and "I told you so's."

State and Federal law aside, this Commissioner is interested in encouraging the most efficient mix of energy resources for the long-run benefit of the Montana ratepayer. After considering all of the testimony before us in this case, I believe this order is a great step in that direction.

My second point is a suggestion born of frustration with the lockstep routine of traditional ratemaking. From my perspective, it seems that we should be making the comparative cost advantages of our state in nearly all forms of energy available to new large electric loads. In Montana those loads usually will be associated with the processing and finishing of many of our raw resources. Yet, ironically, the threat of new large loads on the regulated system raises justifiable fears in the other ratepayers that their own rates will be driven upwards. Those same future increases are just as discouraging to the decisionmakers behind the new large loads. They can see and calculate the consequences of their own additions to the relatively small rate bases we have here in Montana. It is not surprising, then, that primary processing industries needful of large amounts of energy will not justify large new investment in Montana, while not knowing the eventual level of rates for their own use. We have, in other words, a classical "Catch 22."

I suggest that the best way to address this problem is to make independent (unregulated) power supplies available to such new large loads, with the use of voluntary wheeling by the required utilities. Independent suppliers may wish to participate if they believe the terms of a contract with single large customers outweigh the total benefits available under this avoided cost order. Large loads might be interested, even with power costs initially higher, if they could count on a predictably more stable price for the life of their respective processing plant. It is conceivable that a brokered package of, for example, cold weather wind, spring and summer hydro, company-owned cogeneration, traditional firm power from the regulated utility and interruptible load might be competitive in price right now, as well as more stable over the long-run. Ratepayers might be supportive if such arrangements lessened the likelihood of sharp price spikes associated with new additions of regulated generation. Ratepayers might also benefit from the upswing in economic activity normally associated with the presence of energy driven processing plants and decentralized energy producing technologies in Montana. The Commission might be interested as long as the wheeling charge fairly covered the allocated cost of the service and suppliers or users who might have utility affiliates as joint venture partners were not experiencing unfair advantage in wheeling arrangements.

Finally, the utility might benefit by avoiding the risks of large plant additions in response to major unexpected load increases and the subsequent risks of demand constriction in response to general rate hikes. The service charges from any wheeling and any brokering the utility might supply to such arrangements represent new services and new revenue. Income from joint ventures in the independent arena would also represent significant new unregulated earnings. As the ratepayer might enjoy the benefits of a healthier economy, so would the utilities enjoy the benefits of a more gradual increase in peripheral load around new large loads and new independent suppliers.

Since this is only a suggestion based upon my personal observation of several dozen dockets in the last three years, there remains a need to actually attempt it. Perhaps the most realistic way is to have an aggressive utility, or supplier, or large load -- or a combination of all three -- to make a specific proposal to the Commission. It seems to me that a first step has to be made somewhere. With the potential me that such a proposal is needed to direction.

JOHN B. DRISCOLL, Commissioner